NATIONAL
COMPETITION
COUNCIL

NCC Occasional Series

Gas Swaps

firecone

April 2006

REPORT

Gas Swaps

Prepared for

The National Competition Council

Firecone Ventures Pty Ltd
Melbourne

April 2006

ISBN 0-9775368-1-5

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An appropriate citation for this paper is:

Firecone Ventures 2006, *Gas Swaps*, Report prepared for the National Competition Council as part of the NCC Occasional Series, Melbourne.

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The National Competition Council was established on 6 November 1995 by the Competition Policy Reform Act 1995 following agreement by the Australian Government and state and territory governments.

It is a federal statutory authority which functions as an independent advisory body for all governments on the implementation of the National Competition Policy reforms. The Council's aim is to 'improve the well being of all Australians through growth, innovation and rising productivity, and by promoting competition that is in the public interest'.

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Foreword

Historically, the Australian gas market consisted of a series of State based markets, each supplied by a single gas production source via a single transmission pipeline. In the 1990s, the Council of Australian Governments struck agreements aimed at creating a national gas market with competitive supply arrangements. It recognised that a well-developed and competitive gas industry was vital to Australia's economic and environmental future.

The subsequent National Competition Policy gas reforms have contributed to the gas industry's development. Recent investment in new pipeline infrastructure has expanded the geographic reach of gas networks, and new sources and suppliers of natural gas have emerged. However, physical limits on the scope of gas markets still exist—pipeline direction, pipeline capacity and the location of supply and demand all affect choice and competition.

When the Council is considering whether to recommend whether or not a pipeline should be covered under the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code), interested parties sometimes claim that, notwithstanding apparent physical constraints, gas markets are effectively competitive across broad geographic areas and that "swaps" and similar gas trading and financial instruments are a means of expanding a market for gas beyond its physical limitations, particularly in eastern Australia.

In order to increase understanding of this issue the Council commissioned Firecone to consider the role of swaps in Australian gas markets and prepare this National Competition Council occasional series paper. The Council also sought advice on the extent to which financial instruments aid the development of effectively competitive regional markets, the extent to which such markets are independent of limitations imposed by physical constraints, and whether deficiencies in markets for financial instruments create barriers to the establishment of regional markets.

Of course the Council must consider applications for coverage or revocation of coverage on their own merits. Firecone's paper in no way binds the Council, although it should assist parties seeking to analyse competition in specific gas markets as part of their applications under the Gas Code. In particular the Council hopes this paper will assist parties to provide more empirically based analyses of the roles of swaps and financial instruments in relation to physical limitations on gas markets.

David Crawford
Acting President

John Feil
Executive Director

Gas Swaps

A report by
Firecone Ventures Pty Ltd

April 2006

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1 Introduction

The National Competition Council asked Firecone to advise on gas 'swaps'. It asked Firecone to:

- Outline the nature and key characteristics of swaps and other financial instruments in the gas market, and how these may expand a market for gas beyond physical limitations such as those imposed by pipeline direction or capacity and the location of supply and demand for gas;
- Examine the eastern Australian gas industry to assess the extent to which financial instruments aid the development of effectively competitive broad regional markets, and the extent to that such markets are independent of limitations imposed by physical constraints; and
- Identify any significant barriers to establishment of broad regional markets that result from deficiencies in markets for financial instruments, on a short or long term basis.

The full terms of reference are at Appendix A.

This report is structured as follows.

- Section 2 sets out key features of the eastern Australian gas industry.
- Section 3 discusses the role of gas-for-gas swaps in eastern Australian gas industry, and gives our conclusions on the extent to which these liberate the market from limitations imposed by physical constraints.
- Section 4 discusses the role of financial instruments that address timing and price risk issues, such as options.
- Section 5 sets out our conclusions on the extent to which the use of swaps and other financial instruments in the eastern Australian gas sector expands the market for gas beyond limitations imposed by physical constraints.

2 Characteristics of the eastern Australian gas markets

The gas market comprises two distinct but inter-related markets: the market for gas, and the market for pipeline capacity and ancillary services. This section provides background information on the key characteristics of the eastern Australian gas and pipeline capacity markets. The data is drawn primarily from ABARE reports. In brief:

- Production is highly concentrated. Emerging gas suppliers are slowly reducing the level of concentration. Development of a major new production source could increase competition in supply, depending on who developed the new source.
- Consumption is also highly concentrated. A small number of end users account for a significant amount of gas consumption. There are five major gas retailers. Most retailers have a presence across eastern Australia, although with varying strength in different urban centres.
- Production is often located far from final markets. Transportation distances and costs are significant. However, following substantial pipeline development in recent years, most (but not all) urban centres are serviced by two pipelines providing gas from alternative sources of supply.
- The commercial arrangements in the sector are dominated by long-term contracts for gas supply and transportation. The major exception to this is the spot market which operates within Victoria for the purposes of ensuring energy balance in the Victorian transmission network.

2.1 Gas production and consumption

Australia has abundant reserves of gas. The major sources of natural gas for eastern Australian gas markets are the Gippsland and Cooper-Eromanga basins.

Gas demand is forecast to nearly double by 2029/30. Over the same period, supply is forecast to increase by 11% as declining production from the Cooper basin, and later the Gippsland basin, is offset by increased production of coal seam methane. However, by the middle of the next decade, demand is expected to exceed supply[1]. The most likely sources for additional supply appear to be PNG, and in the longer term, north Western Australia.

The eastern Australian gas supply market is dominated by a small number of producers. Currently, three market participants (BHP Billiton, ExxonMobil and Santos) account for more than 95% of contracted supply to eastern Australia. There are a number of emerging gas suppliers. This is leading to a slow decline in the dominance of the three major producers. However, ABARE estimate that these three firms will still control around 87% of the market in 2010.

Gas production in Australia is more concentrated than in a number of markets overseas. The US market comprises 24 major producers, and 8,000 producers in total, connected to final demand through a well integrated transmission network. In the UK, the top four firms account for over 50% of supply.[2]

[1] ABARE (2005) *Australian Energy National and State Projections to 2029/30.*

[2] Allen Consulting (2005) *Options for the development of the Australian wholesale gas market.* Final Report to the Ministerial Council on Energy Standing Committee of Officials – Gas Market Development Working Group.

Consumption is also relatively concentrated: seven firms account for nearly 25% of gas consumption in the eastern Australian market. Most end users prefer to rely on retailers to meet their gas consumption needs.

The commercial arrangements for wholesale gas are dominated by long term, confidential contracts. Typically, these include 'take-or-pay' clauses where the purchaser is required to pay for a minimum quantity of contracted natural gas each year irrespective of whether the purchaser actually takes delivery of it. Upstream facilities prefer to sell gas on a flat load shape, but may be willing to negotiate some flexibility to better match the load shape in the final market.

2.2 Gas transmission

Gas is transported under high pressure from the gas fields to major demand centres via gas transmission pipelines. Gas pipelines operate point-to-point, in the sense that the physical flow of gas molecules is always in one direction along a pressure gradient. The capacity of each pipeline is a function of its diameter, length and the pressure differential between its two ends. Capacity can be increased through adding additional compressor stations.

Historically, major markets within south-eastern Australia have been supplied by a single gas production source via a single transmission pipeline. However, national transmission capacity has increased rapidly from 9,000 km in 1989 to over 17,000 km in 2001 and 21,000 km currently. Recent major investments are listed in Table 1.

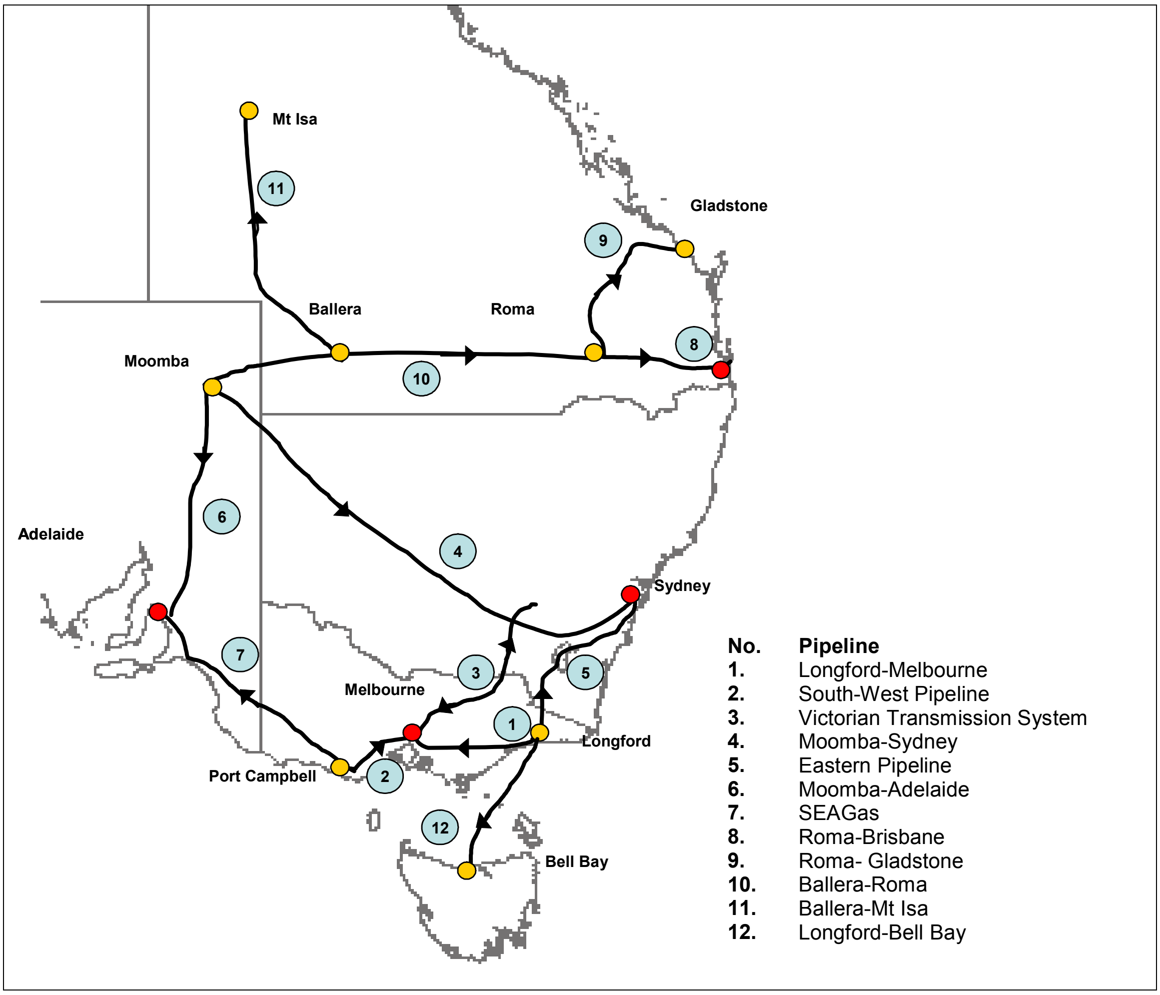
Table 1: Selected recent major pipeline investments

Pipeline	Operational	Connects
Culcairn interconnect	1998	Interconnects Victoria and NSW
South West Pipeline	2000	Connects Port Campbell (Vic) to the main Victorian transmission grid
Eastern Gas Pipeline (EGP)	2001	Connects Longford (Vic) to Sydney
Tasmanian Gas Pipeline (TGP)	2002	Connects Longford (Vic) to Tasmania
SEA Gas Pipeline	2003	Connects Port Campbell (Vic) to Adelaide
VicHub	2003	Interconnects the EGP, the TGP and the Victorian gas transmission system
Telfer pipeline	2004	Connects Telfer gold-copper mine to Port Headland (WA)

As a result of these investments, the gas transmission pipeline system is now closer to a network. Sydney, Melbourne and Adelaide are now each supplied by at least two pipelines, providing access to gas from alternative gas supply sources. In addition, suppliers of natural gas can now sell to a number of end-user markets – gas from the Cooper basin, for example, can be sold into New South Wales, South Australia and Victoria[3] and– giving them diversity of final market.

Figure 1 provides a map of the transmission pipeline system for eastern Australia, and the dominant or only direction of gas flow.

Figure 1: Transmission pipeline system in eastern Australia



Most gas reserves are located some distance from major markets. Consequently, transmission distances and pipeline costs are significant. Table 2 provides illustrative tariffs from a variety of sources.

[3] In practice, the amount going to Victoria is very small

Table 2: Illustrative pipeline tariffs

No.	Pipeline	Length	Current capacity	Ownership	Tariffs	Data sources
1	Longford-Melbourne	145 km	990 TJ/day	GasNet	$0.51/GJ (100% load)	Gasnet (2005) submission to NCC- Revocation of coverage of MAPS NCC (2005) draft recommendation – application for revocation of coverage of MAPS
2	South-West Pipeline		200 TJ/day	GasNet	$0.56/ GJ (100% load)	
3	Vic Trans. System			GasNet		
4	Moomba-Sydney	2026 km	470 TJ/day	Australian Pipeline Trust (APT)	Capacity charge (2006) = $0.03646/GJ/km Throughput charge (2006) = $0.00229/GJ/km	Access agreement – ACCC final approval (2003)
5	Eastern Pipeline	795 km	65 PJ pa (uncompressed)	Alinta Infrastructure Holdings (AIH)	$0.35/GJ (zone 1) $0.76/GJ (zone 2) $1.01/GJ (zone 3)	AIH 2005 Annual Report 2006 reference tariffs
6	Moomba-Adelaide	1185 km	418 TJ/day (fully compressed)	Hastings Diversified Utilities Fund (HDF)	Capacity charge = MDQx365x$0.37/GJ Commodity charge = $0.08/GJ	HDF 2005 Annual Report 2002-2005 Access arrangement
7	SEA Gas	680 km	125 PJ pa	Origin, International Power, CLP	$0.67/GJ	www.seagas.com.au SEA Gas Project Factsheet
8	Roma-Brisbane	440 km	178 TJ/day	Australian Pipeline Trust (APT)	Capacity reservation rate = $0.25/GJ Throughput rate = $0.15/GJ.	APT website Access arrangement
9	Queensland Gas Pipeline	627 km	32 PJ pa (uncompressed)	Alinta Infrastructure Holdings (AIH)		AIH 2005 Annual Report
10	Ballera-Roma	755 km	130 TJ/day (uncompressed)	Hastings Diversified Utilities Fund (HDF)		HDF 2005 Annual Report
11	Ballera-Mt Isa	840 km	98 TJ/day	Australian Pipeline Trust (APT)	$0.80/GJ (principal foundation user) $0.86-$0.96/GJ (other foundation users) $0.96/GJ (other users)	Access arrangement and supporting information paper
12	Tasmanian Gas Pipeline	734 km	47 PJ pa (current)	Alinta Infrastructure Holdings (AIH)	$0.85/GJ (zone 1) $1.80/GJ (zone 2)	AIH 2005 Annual Report 2006 reference tariffs

Like gas supply, gas transportation is dominated by long term contracts. These generally include a fixed capacity payment (expressed as $/Maximum Daily Quota (MDQ)) and a volume charge (based on GJ of gas actually transported). Given high fixed costs, capacity payments are typically a large element of total transport costs.

Certain pipelines are 'covered' by the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code). Covered pipelines are required to offer benchmark tariffs, approved by the regulator, for reference services. Broadly, this equates to a 'cost of service' style of regulation, where total revenues (allowing for forecast demand) are expected to cover efficient costs.

Although the sector is dominated by long-term contracts, some secondary markets have emerged to enable shippers to adjust their long-term positions in response to short-term fluctuations in demand. For example, the three shippers using the Moomba-Adelaide Pipeline System negotiate between themselves to secure additional capacity as required[4].

2.3 Victorian gas market

The gas market within Victoria operates differently. Victoria has an interconnected transmission network where gas can flow in multiple directions. An independent not-for-profit statutory agency (VENCorp) is responsible for balancing the principal gas pipeline network, and managing constraints by soliciting bids to buy and sell gas through its centrally-operated spot market.

While the majority of gas is traded under commercial negotiated contracts, the spot market provides a mechanism for participants to trade their imbalances through a competitive bidding process. It also enables any party to buy or sell gas, as rights to the transport network are not required.

[4] ABARE (2003) *Australian Gas Markets: Moving Towards Maturity* p. 8

3 Overcoming physical constraints to trade

Pipeline direction, pipeline capacity and the location of supply and demand for gas impose physical limitations on the market for gas. This section considers the use of backhaul arrangements and swap arrangements to over come these physical limitations.

3.4 Back haul contracts

Backhaul contracts result in a paper 'transport' of gas in a direction opposite to the aggregate physical flow of gas molecules in the pipeline. It is achieved by displacement against the flow on the pipeline, so that the gas is effectively re-delivered at a point upstream from the point of receipt. Backhaul capacity will vary from day to day. Aggregate backhaul must be equal to less than aggregate forward haul transactions.

Box 1 outlines the use of backhaul arrangements on the South West Queensland Pipeline.

Box 1: Example of backhaul contract

The South West Queensland Pipeline (SWQP) is a 755km pipeline with an uncompressed capacity of 130TJ/d connecting gas producers in the Cooper Basin at Ballera to Wallumbilla. At Wallumbilla, the SWQP connects with separate pipelines to Rockhampton (via Gladstone) and Brisbane. The SWQP has a major transportation contract with the South West Queensland Gas Producers ('SWQGP') which expires in 2012. It has also entered into backhaul arrangements (that is, notional supply of gas in a westerly direction on the pipeline) with a number of shippers including Origin and Energex.

Source: Hastings Diversified Utilities Fund

In principle, backhaul contracts can partly overcome the physical limitations imposed by pipeline direction in that they enable gas to be transported contrary to the flow of gas along the pipeline. However, in practice, the technically available backhaul capacity will vary from day to day: aggregate backhaul must be equal to less than aggregate forward haul transactions, and minimum pressure levels must be maintained within the pipeline for safety and security of supply reasons. Consequently, where pipeline operators offer backhaul arrangements, it is generally on an 'as available', and not a firm basis. This means backhaul contracts may not meet the needs of customers requiring firm access to gas.

3.5 Gas-for-gas swaps

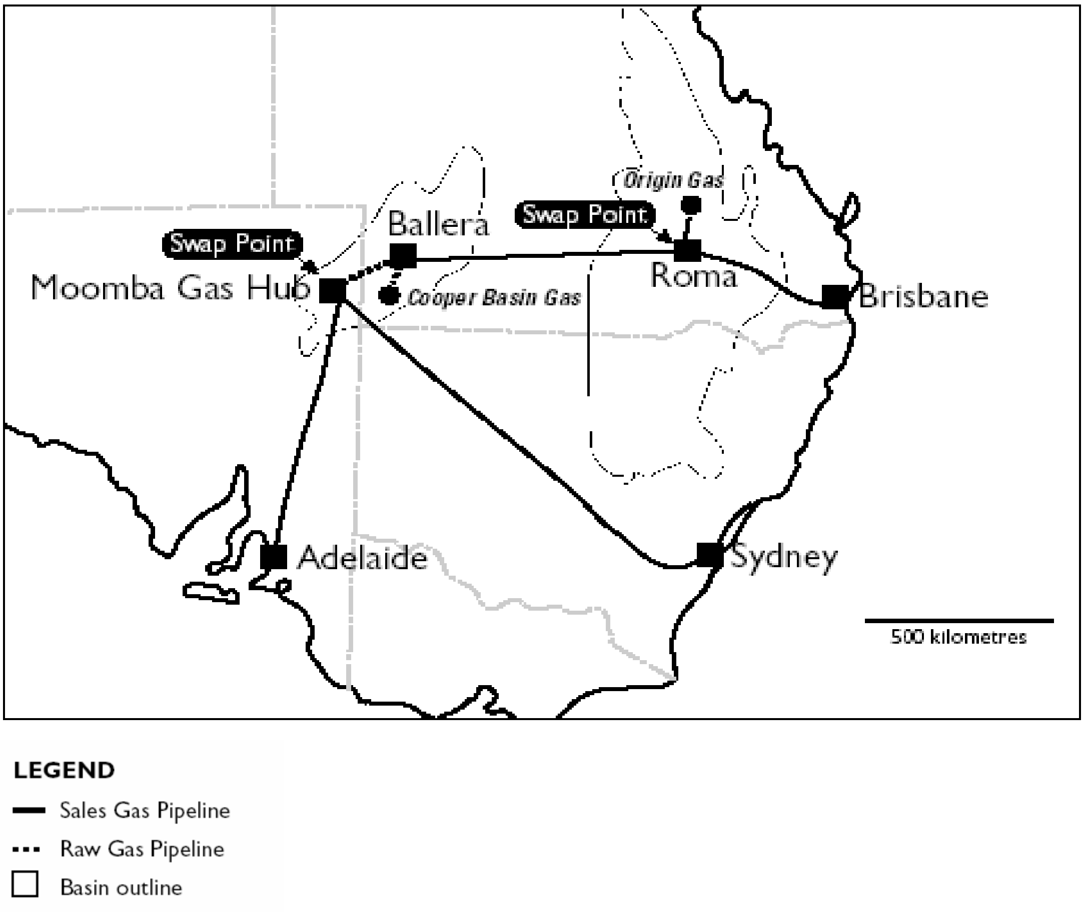
Gas-for-gas swaps involve the exchange of gas at one location for the equivalent amount of gas delivered at another location. The largest and most commonly cited example in the Australian gas market is the Origin/Santos swap, which is described in Box 2.

Box 2: Example of gas-for-gas swap

Origin Energy produces gas from its coal seam gas fields in central Queensland reserves, but many of its customers are located in south-eastern Australia. Likewise, Santos produces gas from its Cooper Basin reserves and has customers located in south-east Queensland.

Origin Energy signed an agreement with Santos and the other South West Queensland Gas Producers to swap gas between Queensland and the Moomba Gas Hub. Origin will deliver gas produced at its central Queensland fields to the South West Queensland Gas Producers at Roma in Queensland. The Producers will then use this gas to meet part of their customer requirements in south-east Queensland. In return for the gas from Origin, the Producers will redirect (swap) an equal quantity of their Cooper Basin produced gas to Origin at the Moomba Gas Hub. Origin is expected to use these swapped gas volumes to supply its customer base in South Eastern Australia.

The agreement extends to 2011, and the volume of gas swapped is variable. The map below illustrates the swap.



Santos summarised the benefits to both parties from this swap as follows:

- Having access to swapped gas at the Moomba Gas Hub eliminates the need for Origin to construct major additional pipeline infrastructure in the short term; and
- The South West Queensland Gas Producers receive payments from Origin (and also benefit from increased revenue from incremental processing at its Moomba Gas Hub, which recovers higher levels of liquids than its Ballera facilities).

Source: Santos Media release, 6 May 2004

Generally, the optimisation of gas supply and transport costs will be achieved within a company, through management of contract positions (and – over time – through changing contract positions). Swaps enable similar cost reductions to be achieved through by two (or more) separate companies through a bilateral (or multi-lateral) deal.

Effectively, swaps can be regarded as secondary markets in gas commodity, where payment is made in kind. That is, two retailers may continue to hold long term contracts for gas supply to particular locations, but may agree with each other exchange the rights to that physical output. Given the location of their load, this exchange will also have impacts on their transportation requirements.

As demonstrated by the Origin-Santos deal (which enabled Origin to avoid constructing additional pipeline capacity between south-east Queensland and Moomba), it may enable the participants in the swap to overcome physical limitations that would otherwise be imposed by the direction or capacity of gas pipelines. In principle, a swap arrangement can allow the companies concerned to sell gas in markets in which they would not otherwise have had a presence. This may allow greater competition in upstream and downstream gas markets.

3.6 Use of swaps in practice

During this study, we consulted a number of major gas businesses on their use of gas-for-gas swaps. This was not a comprehensive survey, and should be regarded as illustrative, rather than fully describing the extent of swaps in the eastern Australian gas market.

All the companies we spoke to indicated that they had done (or were aware of) gas swaps with similar characteristics to the Origin/Santos agreement. All indicated that the scale was minor, and "a few percent" of total sales. Most indicated that swaps only lasted a few months, although some examples of multi-year agreements were quoted.

The reasons quoted for using swaps were:

- Outages or other interruptions to anticipated production;
- Minimising pipeline transmission costs, taking into account high MDQ charges and low backhaul tariffs;
- Smoothing load, given inverse season variation in load shape between retailers at different locations; and
- Supporting entry into new markets, where the retailer does not have adequate existing supply arrangements.

Retailers also stressed to us that their usual approach was to ensure that their retail position was supported by adequate contract cover. Swaps were therefore used for relatively minor volumes, and often in response to unexpected events. The Origin-Santos swap referred to in Box 2 appears to be significantly different from other gas swaps in the eastern Australian market in both its scale and its duration.

3.7 Future developments

In general, gas-for-gas swaps are used by market participants to minimise their gas supply and transport costs. There are several factors that should drive the increased use of gas-for-gas swaps in the future. These include:

- continuing high transport costs, given the location of gas resources and of major consumers;
- a gradual increase in the diversity of upstream facilities, as fields in the Otway Basin come on stream, and given the growing role of coal seam methane in Queensland; and
- a possible increase in transparency of gas sales and transport prices, in line with Ministerial Council on Energy principles for future development of the gas market.

To put it more simply, swaps are used by market participants to minimise delivered gas costs. If there is an increasing diversity of supply options, and greater transparency of supply and transport prices, then that is likely to support more swap activity.

However, there are also significant drivers constraining use of swaps in practice. The first is that major retailers have coverage across the eastern Australian market. They support this with supply and transport contracts that match their retail position. As a result, swaps of the scale and duration of the Origin-Santos swap will continue to be rare. Retailers will ensure long term supply and transport contract cover, and minimise long term costs, through their own contract positions.

A further issue may be the transaction costs associated with swaps. We received conflicting views on this from industry participants:

- Some argued that they would be cautious about entering the market for swaps. This might be taken as an indication that the company was short in a particular market, and so reveal information of value to competitors;
- Others argued that this was not an issue, saying that the industry was generally reasonable aware of different parties' contracting positions, and so the costs involved in revealing this information were low.

More generally, the eastern Australian gas market remains relatively opaque and non-transparent. Other things being equal, this raises the transaction costs of deals such as backhaul contracts and swaps, and increases the benefits of a retailer relying on its own contracting position with upstream facilities and pipeline owners.

As markets become more transparent, transaction costs should decline. One step to assist this may be the development of standard documentation for wholesale trading in natural gas. The Australian Financial Markets Association has established an industry working group for this purpose. Our understanding is that this will initially focus on developing standard documentation to assist secondary markets in gas sales and haulage, and subsequently the possible development of derivatives such as options. Standard contracts and a reduction in transaction costs may result in more active secondary markets for gas sales and transportation, including increased use of gas-for-gas swaps.

Our conclusion is that most gas retailers are going to match their retail positions with direct long term contracts with upstream gas facilities and pipeline operators. However, in the future, increased transparency and reductions in transaction costs may result in increased use of gas-for-gas swaps to minimise costs for a given set of long-term contractual positions.

4 Financial markets for gas

This section discusses the characteristics of financial instruments, and provides examples of some of the ways they are used in energy markets.

By increasing price volatility, energy market reforms have increased demand for instruments to manage price risk. Unsurprisingly, therefore, the growth of energy derivatives has coincided with the liberalisation of energy markets. More generally, the creation of standardised tradeable financial instruments which do not entail physical delivery allows a much large number of parties to enter markets for risk. This creates greater liquidity in the market, and so provides a benefit to all participants.

As we discuss below, these drivers for the development of a financial market have been weaker in the eastern Australian gas market than in some markets overseas, or in the Australian electricity industry.

4.8 Types of financial instruments

A derivative is a financial product, the price of which is directly dependent on the value of one or more underlying commodities, financial securities or other arrangement.

Derivatives allow the trading of rights or obligations based on the underlying product, but do not in themselves provide an ownership right in the underlying asset. For example, a share in the energy sector firm Alinta gives an ownership interest. A call option on Alinta shares provides a right to purchase these shares at a defined price. The price of the Alinta call option is derived from the price of Alinta shares (amongst other things).

Energy derivatives are typically defined with respect to an underlying energy market price, such as the price of gas of a defined quality at a defined location. Some examples of derivatives used in the energy sector are shown in Box 3.

Box 3: Examples of types of financial instruments used in energy markets

Forward contract: a contract to buy or sell a specified amount of a designated commodity at a known date, time and location. Forward contracts are negotiated bilaterally and not traded on an exchange.

Futures contract: similar to a forward contract - but standardised, traded on an exchange, and marked to market daily, with profits (or losses) settled at the end of the trading day. In the UK, the International Petroleum Exchange (www.theipe.com) has traded natural gas futures since 1997. Contracts are against delivery within the UK natural gas grid at the National Balancing Point. Physical delivery is only required if the position is not closed out.

Option contract: provides the right to buy (call option) or to sell (put option) a commodity (or a futures contract or a swap contract) at a defined price. For example, the Sydney Futures Exchange (www.sfe.com.au) lists put and call options for peak electricity in Australian States in the National Electricity Market.

Swap contract: a contract negotiated between two parties to exchange streams of payments over time according to defined terms. For example, an electricity swap may define payments with reference to the difference between an agreed strike price and a reference price (such as the National Electricity Market spot market price at a regional reference node).

Derivatives can be used to manage risk. Forward contracts emerged because buyers and sellers were concerned about movement in prices over time: forward contracts enable both parties to be certain about prices. An energy retailer concerned about spikes in wholesale prices can cap that exposure by buying a call option. Similarly, financial swaps are commonly used to manage price risk that arises as a result of volatile prices. Box 4 provides a Canadian example in which a company uses a swap to obtain a fixed price for gas that it sells through the gas spot market.

Box 4: Using a swap to obtain a fixed price for gas

The Macquarie Power Income Fund (MPIF) owns and manages the gas-fired electricity generator Cardinal Power. Cardinal has entered a power purchase agreement with the Ontario Electricity Finance Corporation (OEFC). Under this agreement, Cardinal sells all of its output to OEFC until 2015. Cardinal has also entered into long term gas supply and transportation agreements, supplying it with gas until 2015. The gas supply contract stipulates minimum purchase volume commitments.

During the summer months, from April to October, and during periodic maintenance shutdowns, the minimum purchase commitments create an excess gas supply. Cardinal on-sells the excess gas, causing exposure to volatility in the gas spot prices. To remove revenue uncertainty from its sale of excess gas, Cardinal has entered into a five year fixed-price gas swap contract with a Canadian chartered bank.

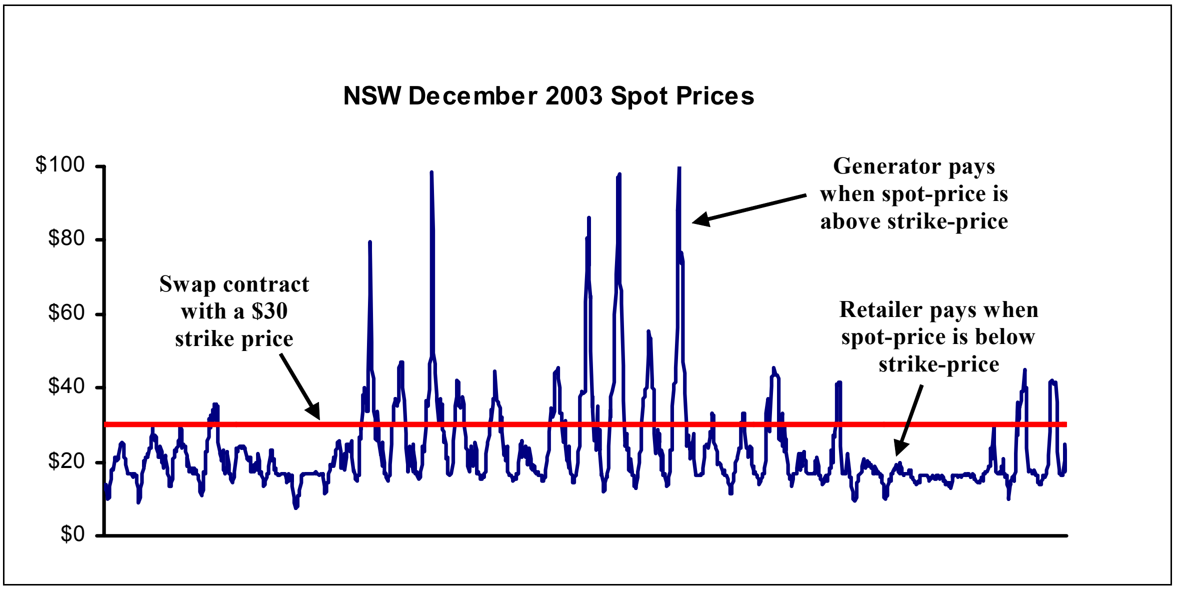
This hedge takes the form of a series of monthly contracts from April-October, 2004 to 2008, under which Cardinal receives a fixed payment stream from the bank in return for making fluctuating payments to the bank based on the market price for gas. The contract volume can be adjusted to reflect the profile of gas available for sale.

Source: MPIF (2004) Annual Report

In the Australian electricity sector, generators and retailers enter into financial swaps to ensure both parties obtain a fixed price in the wholesale market. The spot market price is very volatile, but both generators and retailers prefer price certainty. They may therefore agree a fixed price for a defined volume of MWh over a defined period. If the spot market price is above the agreed strike price, the generator compensates the retailer. If the spot price is below the strike price, the retailer compensates the generator.

This type of contract (illustrated in Figure 2 below) is often called a 'contract for differences' since payments are based on the difference between a strike price and an underlying reference price, such as a price spot market price.

Figure 2: Electricity contract for differences



In the US, liquid spot and futures markets in natural gas have supported the development of markets in gas basis swaps to manage locational price risks. Market participants can fix the price of delivered gas by buying gas futures contracts based on delivery of gas to a central hub) and then swapping the price differential between the hub futures contract and the spot market price at their delivery point.

Box 5: NYMEX gas basis swaps

The New York Mercantile Exchange (NYMEX) natural gas futures contract is widely used as a benchmark price for gas in the US. The price is based on delivery of the gas to the Henry Hub in Louisiana, the nexus of sixteen gas pipeline systems.

The difference between the Henry Hub futures contract price and the spot market price at another delivery point is called the basis. The basis represents the financial value of moving gas from the Henry Hub to the other delivery point. On average, the difference in gas prices between two locations should be the cost of transportation between them. But if gas cannot move between the two points, or until it does move, relative prices will also be affected by the supply/demand balance in each region.

Participants in the physical gas market are more concerned about the price of gas at their own delivery point than they are with the Henry Hub futures price. They use Henry Hub futures contracts to manage fundamental price risk, and then hedge the risk of price differences between Henry Hub and their own delivery point using basis swaps.

NYMEX has introduced cleared over-the-counter basis swaps that allow market participants to manage the price differential between Henry Hub futures contracts and spot prices at other market locations using a standardised instrument, free of counterparty risk, in a more transparent commercial environment. These contracts are quoted as price differentials between the Henry Hub and principal market centres including Alberta, Chicago city gate, Henry Hub, Houston Ship Channel, San Juan Basin, Southern California, Transco Zone 6, Northwest Pipeline Rockies, and the Panhandle Eastern Texas-Oklahoma index.

Source: NYMEX

4.9 Financial markets in gas in eastern Australia

Gas markets in eastern Australia are dominated by long term contracts. Upstream production, transmission pipelines and other physical capacity (such as underground storage and LNG storage facilities) are normally developed under long term agreements, with foundation contractors to sharing the risk with the developer.

Most major gas market participants seek operational flexibility to respond to changes in market conditions and to optimise use of their available resources to meet their day-to-day obligations. The development of secondary markets is affected by the physical characteristics of the gas market, however. While demand for gas has pronounced load shapes, it is relatively predictable. In addition, gas is storable.

Market participants therefore have a number of physical options to manage short term imbalances between actual supply and demand, and their long term contractual positions. For example, gas retailers face the twin challenges of ensuring that they have sufficient gas contracted and that they are able to make enough gas available to meet demand on the day. Provided they have contracted sufficient gas, their options for ensuring that it is available include:

- Negotiating some flexibility in their contracts with upstream gas producers. While producers prefer flat load shapes, they may be willing to negotiate some variation;
- Purchasing firm capacity (MDQ) on transmission pipelines. Pipeline operators set high charges for firm capacity, reflecting their high fixed costs; and

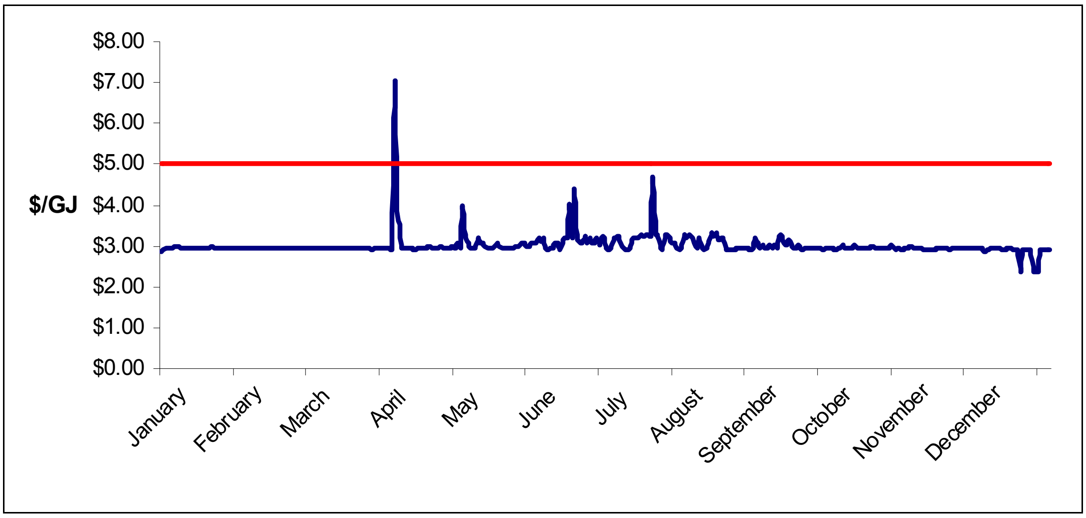
- Other options, such as: purchasing storage, running gas-fired generators on liquid fuels rather than natural gas; or using LNG.

There are secondary markets in both gas and transport services. For example, the three shippers holding capacity on the Moomba-Adelaide Pipeline System negotiate to secure additional capacity as required. During the Moomba gas production facility outage in 2004, the industry contracted quickly to arrange back up supply from Victoria to South Australia. However, the secondary markets are limited. Short term trading in gas and pipeline capacity is conducted on a bilateral basis, with high transaction costs and little transparency to third parties.

The Victorian gas spot market provides a clear and transparent underlying price, which could be used as the basis for a derivatives market (illustrated in Figure 3 below). However, almost no use has been made of financial instruments in this market to date. This has been attributed in part to the lack of volatility in the spot market price. In addition, Victorian market participants have preferred to manage risk through physical hedges rather than financial instruments, for the following reasons:

- Physical contracts provide a broader hedge, covering ancillary services;
- Physical contracts have low counter-party risk, as delivery can be secured against the underlying assets; and
- Contracts for physical capacity in linepack, storage and LNG were allocated to incumbent retailers at the start of the Victorian market, so all retailers had physical contracts to support MDQ risk at the start of the market.

Figure 3: Victorian daily gas market price (2004)



4.10 Future developments

We anticipate that the current reliance on long term contracts in the eastern Australian gas market will continue into the future. The industry is characterised by:

- *High capital costs* for investment in production, transmission and distribution. These investments are specific to gas industry use. The investments are exposed to risk of 'hold-up' after costs are sunk, if prices are not secured through long term contract.
- *High disposal risk*. In Australia, any major development represents a significant share of supply in its target market. There are few players, a need to pool demand to support any

new developments, and high disposal risk. By contrast, in the US gas market, any single project is a small proportion of the total, the transmission network is highly developed, and disposal risk is much lower;

- *A concentrated industry structure*, with limited price transparency and effectively no markets to hedge price risk. Again by contrast, the US gas sector has a large integrated network, a large number of participants, and deep and mature markets at different points in the supply chain.

The result is that investors face high risk, and no ability to manage this through a liquid market. Investors are unwilling to commit billions of dollars to fund projects in the hope that enough customers will eventually emerge. Their response is to reduce risk through securing long term contracts across the supply chain.

Both economic theory and commercial practice suggest that (in the absence of vertical integration through ownership) this is an efficient response to the characteristics of the industry. Given the expectation of continued high level of industry concentration for the future, we anticipate that the current reliance on long term contracts will continue.

Long term contracts do not preclude the development of an active secondary market. As demand and supply conditions change in the short term, parties can trade resource, pipeline and other capacity to minimise costs. The UK, for example, has an active spot market despite reasonably concentrated production and a reliance on long term contracts.

Secondary markets are developing in eastern Australia, particularly in pipeline capacity. If these become sufficiently liquid and transparent, they could provide an underlying price as a basis for a derivatives market. However, we note that, despite the Victorian spot market providing a clear and transparent underlying price, little use has been made of financial derivatives in the Victorian market. As a result, we do not anticipate increased use of financial derivatives in the medium term. The development of financial markets in gas is likely to take many years.

5 Conclusion

Historically, the Australian gas market comprised a series of State-based markets, each supplied by a single gas production source via a single transmission pipeline. Recent investments in new pipeline infrastructure have expanded the geographic extent of markets for gas. Most major demand centres now have access to gas from two different sources, and suppliers of natural gas can now sell to a number of end-user markets.

Pipeline direction, pipeline capacity, and the location of supply and demand still impose physical limits on the markets for gas within eastern Australia, however. In principle, gas-for-gas swaps can enable the participants in these deals to partly overcome these physical limitations, minimising their delivered gas costs. In practice, the scale of gas-for-gas swaps in the eastern Australian markets is currently minor.

Eastern Australian gas markets are relatively non-transparent. Given the high concentration of production and consumption, and high capital costs associated with development of new gas sources and pipelines, the market is reliant on confidential, long-term bilateral contracts. This raises the transaction costs associated with developing gas-for-gas swaps, and increases the benefits to retailers of matching their market coverage to their contracting position with upstream facilities and pipeline owners.

An increasing diversity of supply options may provide a driver for increased use of gas-for-gas swaps in the future. There are a number of emerging gas suppliers. The development of financial markets in natural gas could also create additional drivers by increasing the transparency of gas sales and transport prices, and by reducing transaction costs. However, while secondary markets exist in eastern Australia, they are best characterised as emerging.

Appendix A: Terms of Reference

Scope

Outline the nature of 'swaps' and other financial instruments and how these may expand a market (for gas) beyond physical limitations such as those imposed by pipeline direction or capacity and locational supply/demand for gas. Perhaps contrast these instruments with other instruments that principally address timing/price risk issues (eg hedges, options) and note any interrelationships between the classes of instrument.

Identify key features of relevant financial instruments and the markets for them that increase or limit the substitutability/complementarity of these instruments for/with interconnected physical transactions in gas – perhaps transparency, standardisation, indifference (as to whom one deals with) and liquidity, all add to effectiveness, whereas (excessive) vertical integration or case by case contract specification may lessen substitutability.

Examine the Eastern Australian gas industry in order to assess the extent to which the use of financial instruments aids in the development of effectively competitive broad regional markets and the extent that such markets are independent of limitations imposed by physical constraints. What is the likely extent of broader markets in Eastern Australia in the short (~ current to two years) and long term (~ ten years).

Identify any significant barriers to establishment of broad regional markets that result from deficiencies in markets for financial instruments or other factors. Consider these on a short term and long term basis. Identify any price separations in the Eastern Australia region, their significance and the factors that allow for these.

Appendix B: Role of derivatives in managing risk

This appendix discusses the role of financial instruments in managing risk in energy markets.

Emergence of derivatives markets in the energy sector

Derivatives can be used to manage risk. Forward contracts emerged because buyers and sellers were concerned about future movement in prices. A forward contract enabled both parties to be certain about prices. Swap contracts emerged because buyers and sellers had inverse exposure to financial risk from price changes. Cap contracts emerged because buyers and sellers had concerns about the frequency and scale of intermittent high (or low) prices, and needed a means of effectively setting a cap or a floor on prices. More exotic derivatives – such as weather derivatives – can provide protection against price risks associated with hot or cold weather.

More generally, the creation of standardised, tradeable instruments which do not entail physical delivery allows a much larger number of parties to enter markets for risk. This creates greater liquidity in the market, and so provides a benefit to all participants.

The emergence of derivatives markets in the energy sector has coincided with a period of energy market reforms. This is unsurprising: several features of the energy market reforms have increased price volatility, and so the demand for instruments to manage price risk:

- Industry restructuring has sometimes led to vertical separation between production and retail. If retail tariffs are fixed – by long term contract, competition from substitutes, or regulation – then higher wholesale price will increase producer profits and reduce retailer profits, and vice versa. Integrated businesses have a natural hedge against these price movements. Vertical separation breaks this natural hedge, and so may increase the demand for instruments which hedge against price risk;
- In many cases, the energy market reforms have introduced greater wholesale and retail competition. Competition between alternative sources of supply, with differing costs, increases volatility; and
- In some cases, spot markets have been introduced. Where capacity costs are recovered through spot prices, this can lead to a high level of volatility. For example, in the Australian national electricity market, wholesale spot market prices can range from variable operating costs, towards very high levels which are only capped by the costs of simply foregoing supply.

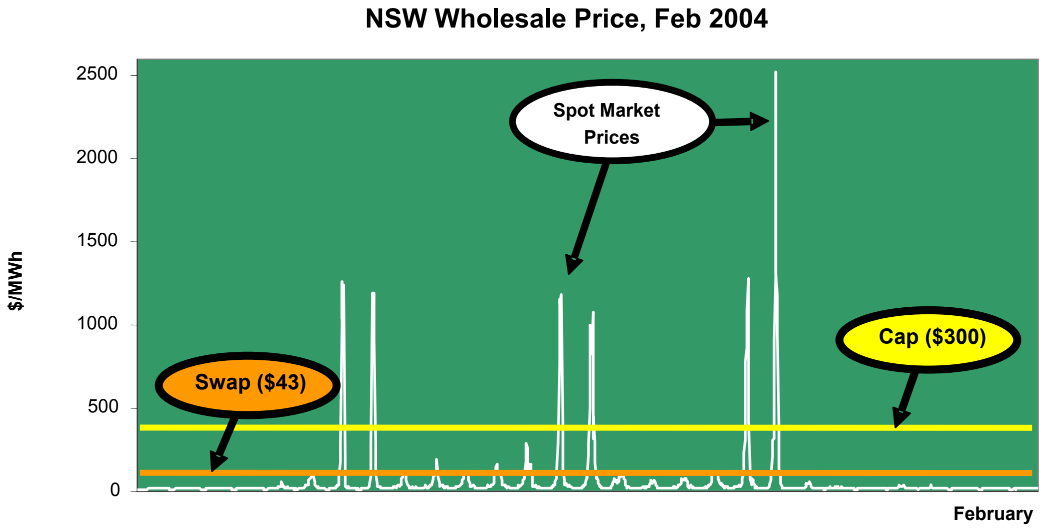
Derivatives markets have therefore emerged in the energy sector in response to increases in price risk, and so demand for instruments to manage these risks.

Impact of derivatives on company value

The role of derivatives in managing price risk can be illustrated with reference to electricity markets. Electricity is essentially non-storable. Demand is very variable, driven in large part by temperature. As demand rises, generation is provided by power stations with higher operating costs. When the supply/demand position becomes tight, spot market prices may also rise well above operating costs towards the market cap.

All of these factors mean that price risk is very high. As a result, both generator and retailer revenues would be highly volatile if they were exposed to spot market prices. Financial derivatives, written with reference to this spot market price, can substantially reduce that volatility.

Figure 4: Swap and cap contracts reduce price exposure



The effect of entering into a derivative contract is therefore to reduce the volatility of cash flows[5]. The actual impact will depend on the nature of the hedge. For example, a call option for a retailer will avoid a 'tail' of potential high losses due to price spikes, while a swap contract will limit both upside and downside.

All hedging activity can reduce the volatility of the cash flows. This raises the question whether it is value increasing for the managers of a business to alter its risk profile. This is similar to the question whether company value is affected by the debt-equity structure of the business. Miller and Modigliani demonstrated, in the 1950s, that financing decisions do not matter in perfect markets.[6] A company's value is determined by its real assets, and the cash flows associated with them, and not the securities that it issues against those cash flows. To quote a standard textbook on corporate finance:

> *"The value of an asset is preserved regardless of the nature of the claims against it. Thus….company value is determined on the left-hand side of the balance sheet by real assets – not the proportion of debt and equity securities issued by the company."*[7]

While this argument is typically applied to the mix of debt and equity finance, it applies equally to the use of derivative contracts to alter claims on the cash flows. For example, Milgrom and Roberts comment:

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[5] This only applies if companies use derivatives to hedge risk, rather than to speculate.

[6] F. Modigliani and M. H. Miller "The cost of capital, corporation finance, and the theory of investment", American Economic Review, 1958

[7] Brealey, Myers, Partington and Robinson, "Principles of Corporate Finance" , Australian edition, p. 493

> *"The ideas used in the Modigliani-Miller analysis can be applied to other financial decisions besides the choice between debt and equity…[and] can be applied to all the diverse and complicated financial instruments that are used in modern financial markets, including options, warrants, callable bonds, convertible bonds and so on. In each case, the argument is that the investor can put back together the parts of the return that the firm has separated….[The] essential message is that a firm can no more change its value by divvying up its earnings differently than increase the weight of a cake by cutting the pieces up in different sizes and shapes."*[8]

This creates a paradox. The liberalisation of energy markets has created greater volatility in prices and company earnings. Theory suggests that, in a perfect market, shareholders could diversify at little or no cost. There should be little value in companies taking this decision on behalf of shareholders. However, companies do actively pursue hedging strategies which reduce the volatility of their earnings, rather than leaving this to shareholders.

One argument could be that managers hedge to protect their own reputations. In other words, it might not be in shareholders' interests for energy companies to hedge, but managers still might do this to avoid the risk to their reputations that arises from poor financial performance or bankruptcy. However, the widespread increase in use of derivatives suggests that this is – at best – only a partial explanation.

The most convincing explanations relate to transaction costs. If individuals could costlessly determine their own preferred position on the risk/return trade-off, then financial markets themselves would enable an efficient allocation of risk. Intermediaries – including the managers of risk within companies – would have no role to play. However, this argument would be weakened if there was evidence of significant transaction costs, and in particular of differences between the costs at individual and company level.

There are two main reasons why shareholders may not be able to costlessly adjust their position on the risk/return frontier. The first is asymmetry of information. It is – to state the obvious – extremely hard for individuals to assess the risk borne by an energy sector company, and to adjust their portfolio in response to that risk. The second, and related, point is the fixed costs in evaluating these risks. Financial intermediaries are better placed to carry out this function than individuals, because those high fixed costs can be spread.

If individuals face high costs in assessing risk, then they are likely to be willing to pay other parties to do this on their behalf. This fits well with observed behaviour. Individuals make significant use of financial intermediaries, such as banks and pension funds, to manage their interactions with the financial market. This reliance on intermediaries has gone up, despite the significant reduction in the costs of participating in equity markets.

Similarly, derivative markets are used by corporations exposed to price risk, or financial intermediaries trading risk, rather than by individuals to adjust their desired risk/return trade-off:

> *"The contrast between theory and reality is perhaps most apparent in the area of risk management. Arguably the most important change in intermediaries' activities that has occurred in the last thirty years is the growth in the importance of risk management activities undertaken by financial intermediaries."*[9]

[8] Paul Milgrom and John Roberts, "Economics, Organization and Management", 1992, page 459
[9] Franklin Allen and Anthony M. Santomero, "The Theory of Financial Intermediation", Wharton Financial Institutions Centre, 1996

This analysis is borne out by looking at actual behaviour in financial markets and the way in which financial assets are marketed. Considerable effort goes into the separation of relatively low risk assets – pipelines, contracted power stations – from higher risk assets. Packaging these assets into funds with a clearly defined risk profile has been a growth industry over recent years.

A second reason why hedging may increase value is that it reduces bankruptcy risk. Although shareholders may be able to adjust their risk exposure through diversification, they face significant costs if a firm moves into bankruptcy. As a result, reduction in bankruptcy risk enhances company value.

Our conclusion is that hedging can add value by making it easier to assess risks, and by reducing the possibility of bankruptcy. If the arguments above are correct, derivatives markets may reduce the cost of capital and this may lead to a higher level of capital investment than would otherwise be the case. However, these are minor and indirect effects. Essentially, purely financial instruments are used to manage risk and do not affect the nature of the underlying physical market.